Economic evaluation of hybrid off-shore wind power and hydrogen storage system

Loisel R.[1,2], Baranger L.[1], Pardo S.[1], Chemouri N.[1]

Abstract

This research evaluates the economics of a hybrid power plant consisting of an off-shore wind power farm and a hydrogen production-storage system in the French region Pays de la Loire. It evaluates the concept of H2 mix-usage power-to-X, where X stands for the energy product that hydrogen can substitute such as gas, petrol and electricity. Results show that a complex H2 mix-usage design would increase investment cost in too many infrastructure components and would significantly decrease the profits. Resizing the project would result in providing two energy products only, such as power-to-power and power-to-gas or alternatively power-to-mobility and power-to-gas services. Hydrogen production costs of selected projects would range between 4 and 13 €/kg of H2 as a function of the application type, of oil and gas prices and of expectations of further reduction in the electrolyser and fuel cell investment cost.

Keywords: off-shore wind, hydrogen, power-to-X multi-product usage, optimal sizing, France

1. Introduction

Development of hydrogen production and storage has emerged worldwide with the increasing prices of oil and gas, with renewable energy deployment and concerns over the climate change and security of energy supply. Clean hydrogen could reduce carbon emissions, in substitution to coal, gas and oil, and could reduce the local pollution from road traffic as well (UNEP, 2006). Hydrogen could support the integration of intermittent renewables, by avoiding power curtailment, electricity grid congestion and by improving the system reliability in remote areas (Aguado and Ayerbe, 2009; Korps and Greiner, 2008).

In Europe, the Fuel Cells and Hydrogen Joint Technology Initiative has been launched in 2008 as a public private partnership aiming to accelerate the market introduction of hydrogen technologies by supporting research, development and demonstration activities.[3] Among European Union Member States, Germany, Spain, UK and France have developed various pilot plants of hydrogen production and storage; for an international review of hydrogen pilot plants see Gahleitner (2013). In France, the national Association for Hydrogen and Fuel Cells has been created in 1998 for supporting the development of hydrogen technologies and fuel cells.[4] At a regional level, in the French region Pays de la Loire, the initiative *Mission Hydrogène* has been launched since 2005 demonstrator projects on hydrogen uses for marine and fluvial applications.[5]

[1] University of Nantes, IEMN IEA, Lemna

[2] Corresponding author: rodica.loisel@univ-nantes.fr; +33 (0) 2 40 14 17 35

[3] http://www.fch-ju.eu/

[4] http://www.afhypac.org/fr/accueil

[5] http://www.mh2.fr/en/

Hydrogen can be used to produce electricity (power-to-power), it can be injected into the natural gas pipeline network (power-to-gas), it can fuel a natural gas power plant or the production of second generation biofuels (power-to-fuel), and it can be used as a fuel in transportation (power-to-mobility). This research develops the concept of power-to-X and evaluates to what extent revenue sources could increase from multiple hydrogen usage on different energy market segments.

The research on the economics of hydrogen shows different perspectives for the market development, based on different cost ranges. The overall cost of hydrogen includes the hydrogen conditioning, compression, storage and distribution. Hydrogen technologies have high investment costs and also high energy losses during power to hydrogen and hydrogen to power conversions. Moreover, when combined with intermittent renewables, the technical lifetime of the electrolyser can be further reduced (Jorgensen and Ropenus, 2008).

The hydrogen cost varies from 5 €/kg to 30 €/kg of H2 as a function of the size of the equipment. A large-scale hydrogen plant could reduce this cost at 3 €/kg of H2 produced for an electricity cost of 40€/MWh (CEA, 2012). The most important cost part is the fixed cost of investment. As for variable cost, the most important component of the production chain is the cost of the electricity input.

This research investigates a case where the power used to generate the hydrogen comes from renewable energy and it is infed at zero cost. This translates into a contractual arrangement which is hybrid system-specific, where the two operators, wind and hydrogen, share their costs and benefits. The economic evaluation is based on the optimal operation of wind power and hydrogen production by means of a dynamic optimization model which maximizes incomes on the market. A set of technological and economic constraints apply, from both demand and supply sides. The potential demand for hydrogen is estimated with hydrogen as a substitute for primary and secondary energy sources: natural gas, electricity and fuel for marine and road transportation. On the supply side, constraints are mainly the wind profile and the available power to generate the hydrogen. At equilibrium, the issue is to constantly match the intermittency of wind power with the continuous demand for hydrogen in a case of fixed commitment with refueling stations for cars and fishing vessels.

The remaining paper is organized as follows. The section 2 describes the study case and the database, the section 3 details the model developed and the section 4 discusses the results and the policy implications. The concluding remarks show under what conditions hydrogen storage may be viable as a future investment option to help managing systems with intermittent renewable generation and to substitute the scarce and carbon-emitting fuels such as gas and oil.

2. Study case

2.1 Description of the infrastructure

Within its National Renewable Energy Action Plan, France has committed to achieve a 23% share of energy generated by renewables in its final energy consumption by 2020 (NREAP, 2009). Among energies from marine sources, off-shore wind power will represent around 6 000 MW, the equivalent of 1 200 wind turbines to be installed off the French coast.

The study case considers an off-shore wind power farm installed in the area of Saint-Nazaire, a French region with large off-shore wind potential and no grid interconnections to other countries. The base case assumes the large-scale deployment of off-shore wind turbines of 1 GW by 2030, and the development of hydrogen and fuel cells as a technical support to the wind power integration. This is a hypothetical project where a storage facility is built close to the offshore wind farm that is connected to the rest of the power system via a dedicated transmission line. The study investigates the way to design the wind-storage-transmission system within the strategy to avoid the wind power curtailment due to limited grid line capacity. The power can be transmitted to the grid by either the wind plant or the storage-fuel cell component of the hybrid plant.

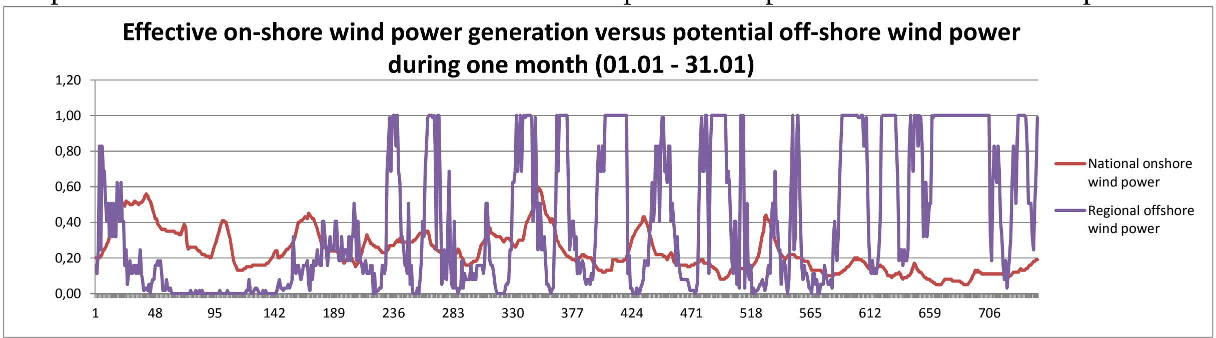
The hydrogen power plant consists of a polymer electrolyte membrane electrolyser, which is a suitable technology for intermittent energy sources, and two compressors with high pressures of 200 bars and 700 bars for power-to-power and power-to-mobility applications respectively. Compressed hydrogen is supplied to the gas network or to storage tanks adapted to each pressure type (200 bars and 700 bars). The auxiliary equipment includes also a fuel cell for electricity generation supplied to the local grid. Efficiency rates are reported in Table 2 along with the cost structure of components.

2.2 Wind power potential

The wind farm consists of more than 80 *Haliade^{TM}150-6MW* turbines. The database of the wind power potential consists of data provided by a weather station in 2013, which is located 40 km from the wind farm, on Belle-Ile Island, at an altitude of 34 m. The data is collected at hourly step and relates to the wind speed, temperature, relative humidity and air pressure. Wind data is adjusted for an altitude of 100 m corresponding to the hub height of each machine. Considering the physical limitations of wind availability, energy conversion, component efficiencies and mechanical losses, a total capacity factor of 36% is obtained.

The next part analyses the intermittency of the regional wind power potential. The first graph compares two sets of hourly wind power generation data for the month of January: the blue line represents the potential production of the offshore wind power cluster, whereas the red line shows the actual electricity generation in 2013 by all the onshore wind farms installed in France. While it is possible to have no offshore electricity generation in the study case, the onshore production is always positive due to uncorrelated wind profiles at a national level. This comparison shows that the off-shore regional potential displays more intermittency, both in frequency and in amplitude, than the on-shore aggregated wind power flow, justifying therefore the need for back-up or storage capacities. At a national level, it is the residual intermittency, defined as the remaining fluctuating output that cannot be transported by the grid line, which may endanger the network stability therefore.

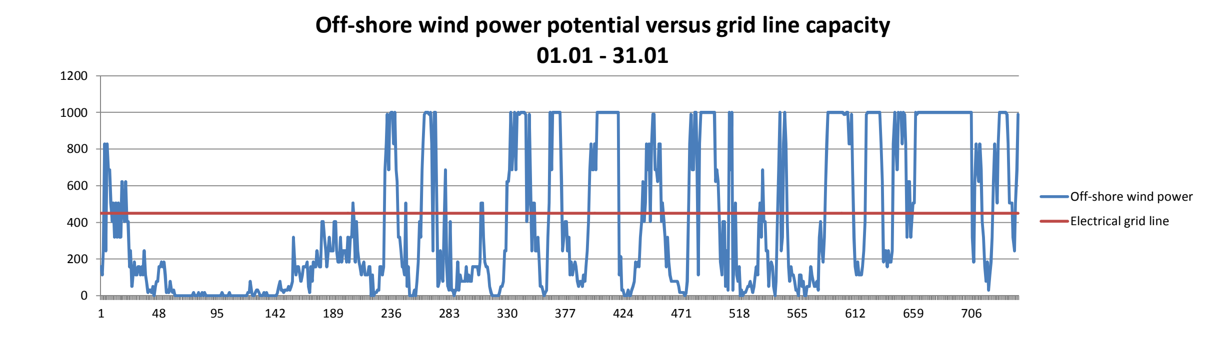
Graph 1. Fluctuation of effective on-shore wind power and potential off-shore wind power



The wind excess which cannot be transported by the grid is represented for one month in the graph below. Variable electricity generation by the offshore wind power cluster is plotted against the existing grid capacity in the western part of Pays de la Loire. All the power generation above 450 MW represents a surplus as a result of transmission line congestion.

Calculations show a potential 35% wind power curtailment out of the total wind potential which could be used instead for hydrogen production.

Graph 2. The potential wind power and the grid transmission line



Project sizing consists of optimizing the wind-hydrogen production and storage capacity that matches the power and hydrogen demand under the financial investment constraint and the infrastructure size. The experience with the hydrogen pilot-plants shows that the design and sizing, control and system integration of hydrogen plants have a great influence on their overall efficiency, reliability and economics (Gahleitner, 2013).

3. Methodology

A dynamic optimization model is built to maximize the incomes of the wind power and hydrogen on the market, under technical and economic constraints of the wind inflow, the transmission grid line and the installed capacity of wind and hydrogen plants.

3.1 The model

The computational model simulates the operation of wind power and hydrogen applications on the market. This is done by means of a single unit dispatch dynamic model, which optimizes the hourly operation of the electricity generation and storage over a year, given its technical constraints. Details of the model can be found in the Annex 1. The model is deterministic and aims to maximize the annual value of the wind-hydrogen, i.e. revenues less operating costs, given exogenous hourly power, oil and gas prices, and the hourly wind potential. As a price taker, the storage does not influence wholesale electricity prices. The hybrid power system operates in optimal market conditions and of perfect information on the power price over one year. Market conditions are defined with respect to value drivers such as the evolution of the spread of wholesale electricity prices between peak and off-peak periods, and the share of the storage capacity sold on the reserve market.

The model reports whether investing in the hybrid wind-hydrogen system would be cost effective in the base case scenario. Investment in wind and hydrogen is not a decision variable in the model. Rather the plant capacity available is specified exogenously. The economics of the project is assessed by calculating a uniform €/MWh value of the hybrid plant over its economic lifetime, that is the net present value (NPV) indicator.

$$NPV = \frac{\sum_{t=1}^{T}[(REV_t - COST_t)/(1+r)^t] - INV_0}{\sum_{t=1}^{T}[EG_t/(1+r)^t]}$$

where t is the year, T the economic life in years, REV the annual revenue from the sale of energy and ancillary services, COST is the annual cost of operation including the electricity cost if any and the variable operational and maintenance cost incurred as a result of performing normal generation cycles, INV_0 is the total investment cost, EG is the annual electricity sold on the market, and r is the discount rate.

The NPV indicator is calculated as the difference between the present value of the cash inflows and outflows during the project's economic life, and the investment cost, divided by the plant's discounted net generated electricity.

Revenues streams are from the energy provision to the wholesale market and from the reserve and power provision to the system. The wholesale market price is endogenously computed in a separate multi-unit power plant dispatching model described in Loisel (2012). For reserve remuneration, it is considered that only tertiary reserve is supplied and it paid at fixed prices of 18.12 € by MW by hour for the capacity and of 10.43 € by MWh for the energy delivered. [6]

Costs are considered in terms of their variable and fixed components, and are presented in the Table 2. Variable costs account for the power withdrawn from the grid, and the variable costs of the system operation. Fixed costs account for the fixed annual operating and maintenance costs, and for the investment costs. Investment costs are annuitized, taking account of economic lifetime, the construction time and the discount rate.

3.2 Scenarios in 2030

The main assumptions made in the scenarios for 2030 (section 3.2.1) concern the energy demand (3.2.2), the cost structure (3.2.3) and the price evolution (3.2.4).

3.2.1 Scenarios description

Several scenarios are built for the 2030 horizon, assuming different architectures of the hydrogen system design as a function of the energy applications which are covered:

1. A first scenario assumes a complex system power-to-X covering all power, gas and fuel applications, *SCE_H2-to-X*.
2. A second scenario assumes that only one application is done, in order to evaluate cost and benefits for one market segment only, *SCE_Power*, *SCE_Gas*, *SCE_Fuel*.
3. Combinations of applications are also done in order to diversify the supply, *SCE_PowerGas*, *SCE_FuelGas*. A third combination would be possible, consisting of H2-to-power and H2-to-fuel applications, but the infrastructure would be too heavy, since it would need both types of compressors and storage tanks, at 200 bars and at 700 bars as well.
4. For comparison purposes, it is tested the case where the power used to produce the hydrogen is withdrawn from the local grid, *SCE_H2only*. The power fed into the electrolyser has a cost in this case, which is the market power price. This case makes the contrast with the wind power used to generate the hydrogen gas for free.
5. It is also tested the case where the wind power operator acts alone, without the support of the hydrogen production and storage plant, *SCE_Wind_only*.

3.2.2. The energy demand

The Table 1 summarizes the assumptions on the demand for hydrogen by energy type.

Table 1. Demand for hydrogen by market type

[6] http://clients.rte-france.com/htm/fr/offre/telecharge/20140101_Regles_SSY_approuvees.pdf

Usage	Demand t H2 during one year	Assumptions
Power to Power	No fixed demand	Hourly constrained by the grid line capacity (450 MW)
Power to Gas	No fixed demand	Hourly constrained by the pipeline capacity
Power to Road	117	The gas station supplies 300 vehicles and 6 buses.
Power to Shipping	102	The refueling station supplies 18 small boats and 3 big capacity ships,
		with autonomy of 24 h and 48 h respectively.

Demand for bus and vehicle refueling stations. The refueling station supplies at a regularly basis 300 cars and 6 buses. The demand for hydrogen is estimated based on the assumptions that the yearly distance covered by a car is 10 000 km and that 1 kg of H2 is required to drive 100 km. This means a daily demand of 0.32 kg H2 for a car, and of 37.5 kg H2 for a fuel cell bus (Le Duigou et al., 2011). The supply of refuelling station is a fixed commitment which occurs every three days at 10 o'clock am, by means of adapted trucks.

Demand for maritime fueling stations. It is assumed that 21 boats refuel at the hydrogen station. There are two ship types, small and big, which implies more or less autonomy and therefore a different frequency for refueling. Small boats needs 24 hours fuel autonomy, while big boats need fuel charging for 48 hours. Small vessels refuel every day and it is assumed that the refueling station planning provides three timelines during the day to fuel all the 18 small boats, at 8 am, at 4 pm and at 12 pm. The remaining 3 boats have a large reservoir capacity and they refuel every 48 hours; with a refueling planning, every 16 hours, one big capacity is refueled at shipping refueling station in this study case.

Demand for power. There is no fix commitment to supply the power market; H2-to-power is instead price responsive: the hydrogen is transformed into power when the electricity price is high under the constraint that enough hydrogen is compressed and stored well in advance. Since the power demand is large enough at a regional, national and even European level by 2030, there is no constraint set on the supply of H2-to-power vector. The only constraint is the limit of the grid line which has to transport the electricity from the fuel cell device to the system operator; this sets an hourly constraint on the power delivery, which is the nominal capacity of the grid of 450 MW.

Demand for gas. With increased energy markets liberalisation in the European Union, less long-term contracts for gas are assumed to be effective by 2030, and that they will be replaced by spot short-term transactions. Similarly with the H2-to-power supply, no fix commitment is assumed in the case of H2-to-gas either. The limit fixed however is the physical capacity of the pipeline which can carry the gas during one hour, such as the hydrogen could be transported and sold on the market.

3.2.3. Hydrogen and wind cost assumptions

The Table X report the main cost assumptions for both off-shore wind power and hydrogen plants.

Table 2. Cost and efficiency specifications of wind-hydrogen technology components

Technology		Investment cost, €/MW	Efficiency, %
Wind plant		2 000 000	99%
PEM Electrolyser		2 000 000	65%
Compressor 200 bars		2 000 000	91%
Compressor 700 bars		2 200 000	85%
Storage 200 bars		1 000 000	90%
Storage 700 bars		2 000 000	90%
Fuel cell		1 000 000	55%

Source: Ademe (2013), Menanteau et al. (2010)

Cost structures are issued from various studies with cost estimates for each technology component. For instance, the global system for power-to-power application includes an electrolyser, a compressor with pressure of 200 bars, a storage tank at 200 bars and a fuel cell; the round trip efficiency is of 29%, reflecting improved performances compared to the current available technologies, of around 25%.

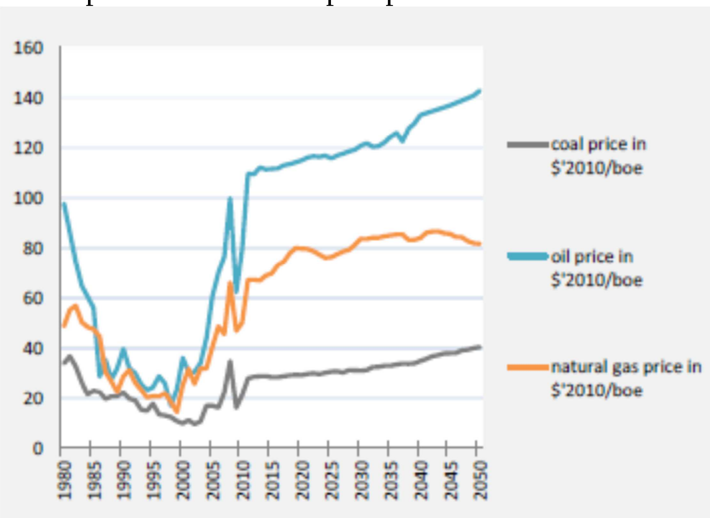
3.2.4. Energy price evolution

Revenue streams of wind-hydrogen plant are from selling the power on the wholesale market and to the power reserve market, and from selling the pure hydrogen to the natural gas market at the market price of natural gas, and to the hydrogen refueling stations at the oil market price.

The hourly wholesale spot prices in 2030 are derived from a power plant dispatching model run for the French power system in the year 2030; see a description of the model in Loisel (2012). For our analysis, we assume that the storage operator is a price taker in the wholesale market and that the plant is sufficiently small so as not to affect prices.

The oil and gas prices are documented from the report on the European Commission (2013) on energy trends by 2050. Their variations by 2030 could be considered as being optimistically low as compared to other price projections; see for instance the EIA report (2013). Hence sensitivity tests are conducted for the economics of hydrogen with concern to energy price variation (section 4.3).

Graph3. Fossil fuel import prices



Source EC (2013)

4. Result analysis

4.1. Optimal sizing of the infrastructure

The Table 3 reports the optimal design of the hydrogen plant for a given wind farm installed capacity and a transmission grid line. The data for each system component arise from our simulations. The electrolyser, the compressors at 200 and 700 bars, and the corresponding storage and fuel cell capacities are chosen so as to meet fixed fuel demand and to obtain maximum profitability for the entire system. Because of very high investment costs, component oversizing is avoided. Excess wind electricity generation can be absorbed in order to reduce grid congestion, but this is not the objective function.

Table 3. Optimal size of the hydrogen plant by scenario

	Scenario						
	Mix usage		Single application			Two applications	
MW	H2-to-X	H2 only	H2-to-Power	H2-to-Gas	H2-to-Fuel	H2-to-Gas, H2-to-Power	H2-to-Gas, H2-to-Fuel
Wind plant	1000	1000	1000	1000	1000	1000	1000
Electrolyser	170	170	100	130	1,1	170	170
Compressor 200 bars	80	80	80	-	-	80	-
Compressor 700 bars	1,2	1,2	-	-	1,2	-	1,2
Storage 200 bars	900	900	900	-	-	900	-
Storage 700 bars	200	200	-	-	200	0	200
Fuel cell	50	50	50	-	-	50	-

Results show that the wind power curtailment avoiding can be low in some simulations, about one third from the total excess. The installed storage capacity and the hydrogen production could not reduce the wind power curtailment further, due to limited capacity to store the hydrogen. It should be noted that when the wind power is in excess, the hydrogen storage cannot discharge the power loaded since the transmission line is used at its maximum capacity by the wind farm. The wind excess is recorded during several consecutive hours, and the storage capacity attains its filling limit very quickly.

The possibility to discharge the storage or to produce hydrogen during the period of wind excess could be limited by a temporary absence of demand for hydrogen as fuel, by the limited capacity of the gas pipeline or the congestion of the electrical transmission line. The power-to-power application occurs under the double condition that the transmission line is available and that the system needs additional power.

These constraints together with the transmission line sharing condition, restrain the charging factor to 47% over the year for the electrolyser, to 62% of the compressor at 200 bars (77% at 700 bars), to 51% and 48% of the storage at 200 bars and at 700 bars respectively, and at 55% of the fuel cells.

4.2. Model results

The next table records the results obtained in terms of profitability for all scenarios considered. For interpreting the economics of projects, when the NPV indicator equals zero, the stream of income enables the investor to exactly recover the project's investment costs during the economic lifetime of the project. A negative value for the NPV indicator shows the additional value required for each unit of generated electricity in order for the investor to exactly recover the project's investment and financing costs (also called the *missing money*). A positive value for the NPV indicator would show that the project makes an economic profit over its economic lifetime.

Table 4. Results of model simulations, by scenario in 2030

Results, 2030	Scenario							
		Mix usage		Single application			Two applications	
	Wind_only	H2-to-X	H2 only	H2-to-Power	H2-to-Gas	H2-to-Fuel	H2-to-Gas, H2-to-Power	H2-to-Gas, H2-to-Fuel
Wind power generation, GWh	2 123	1 931	2 103	2 015	2 124	2 124	1 934	2 121
Wind to H2, GWh	-	800	480	-	499	-	0	-
Withdrawal, GWh	-	361	542	377	-	10	355	6
Production of H2, t	-	20 911	18 402	14 387	8 981	276	20 731	11 096
Potential curtailment, GWh	**963**							
Avoided curtailment, GWh	0	608	460	314	499	958	356	356
NPV, €/MWh	-40	-114	-305	-102	-25	-64	-93	-46
Cost Wind-H2, €/MWh	-	199	-	186	118	154	178	139
Cost of H2, €/kg	-	**12**	**45,5**	**6,2**	**3,9**	**5,1**	**5,9**	**4,6**

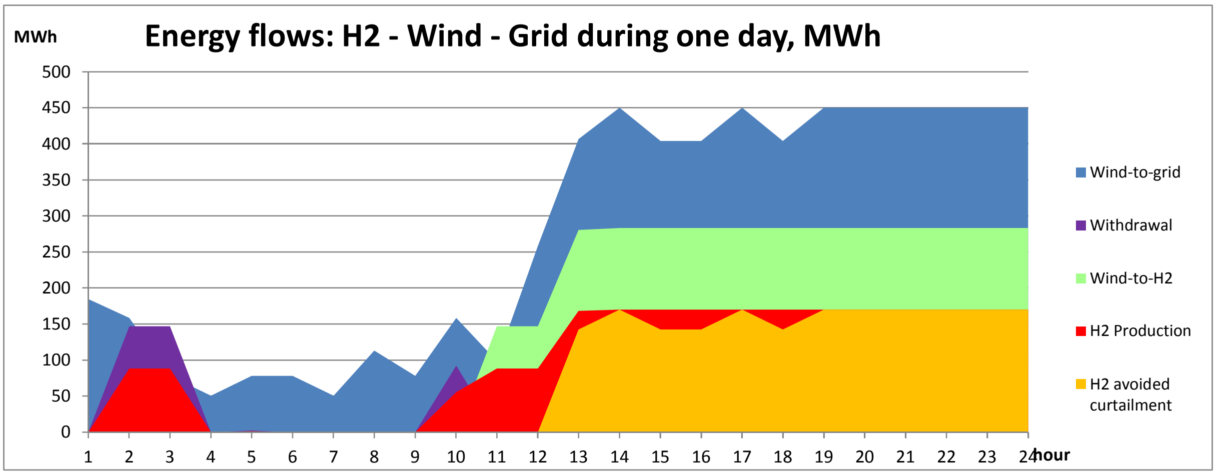
None of the project is economically viable under the assumptions set in our study case, since the indicator of the NPV is overall negative, despite optimization of the operation and sizing. The comparison of different scenarios shows that the highest loss is recorded in the case *SCE_H2only*, since the operator should pay for the electricity consumed for the hydrogen production. The second worst economic case is the mix-usage wind-hydrogen hybrid plant, due to the high investment cost of all the hydrogen system components. Cumulating hydrogen utilisation vectors which do not use the same process infrastructure harms the viability of the project. For instance, the H2-to-Gas application, which has the best NPV result, is using the existing transport-distribution-storage infrastructure of the natural gas and hence has limited infrastructure costs; for the other applications, additional investments are needed for auxiliary equipment.

This is why the application H2-to-gas, using only the electrolyser equipment, is easy to combine with other application such as H2-to-power and H2-to-fuel. As a reminder, the demand for gas is not fixed since it concerns the spot market and not the supply of a particular power plant, which would instead constrain the production and the supply of hydrogen. The potential demand for hydrogen of a combined heat and power plant would have a continuous load charge curve, as presented in MEEDDM (2010). The study case considers transactions on the spot gas market, where the supply is discontinuous and driven by the price only, with no commitment contractually fixed in advance as for refuelling stations.

The costs and revenues structure of the hybrid wind-hydrogen plant in the scenario *SCE_PowerGas* indicates the high share of the investment cost; at the revenue side, the wind revenues are the highest. Investing in a hydrogen plant to avoid the power curtailment has a high cost, with relative low incomes while the hydrogen-to-power is sold at a relative low power market price.

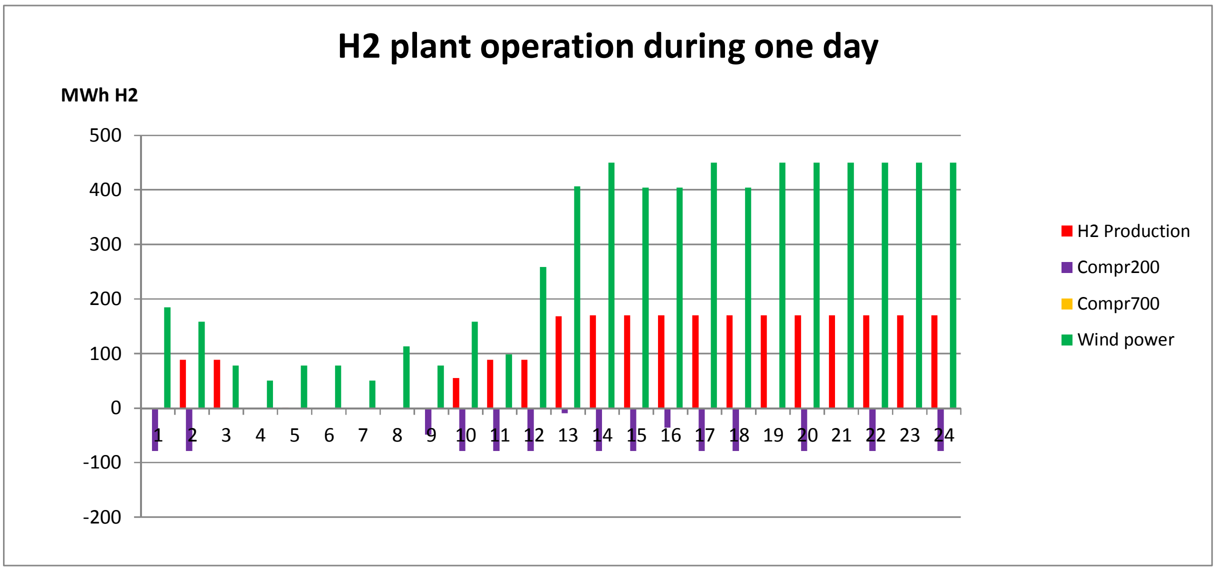
The graph below shows the energy trade-off between the wind power supplied to the TSO (Transmission System Operator) and the wind power used for the hydrogen production. When the power grid limit of 450 MW is not attained during the hydrogen production, this means that the wind power could have been supplied to the power market. Yet, due to low power prices, it is more economically interesting to produce hydrogen during those hours; or, due to a fixed fuel demand constraint, the system must produce hydrogen to can supply the refuelling stations.

Graph 4. Wind and hydrogen energy flows during one day



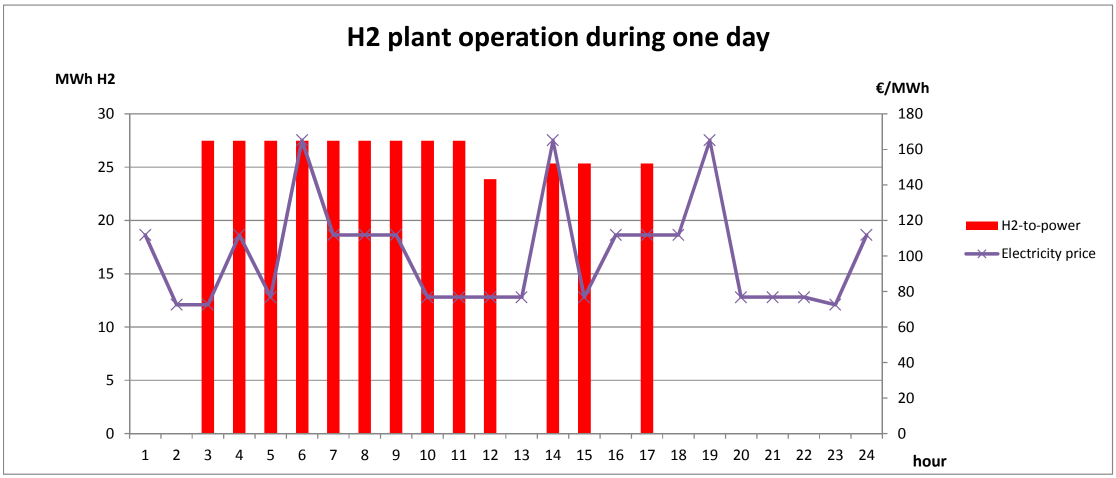
The hourly operation of the wind-hydrogen hybrid plant during one day in the next graph illustrates the wind power generation, the hydrogen production and the gas compression at different pressure levels. The decision for the usage of the hydrogen is driven by the market prices of different energy product and also by the technical constraint, such as the compression capacity or the limit of the storage tanks. Fixed demands for refuelling the cars and boats stations can add to the decision of the timing for hydrogen production. Continuous production of hydrogen could be an advantage to the hydrogen system from technology usage point of view, since it would avoid too frequent start-up and shut-down operations, which would add fatigue and stress to the system and materials (Gahleitner, 2013).

Graph 5. The operation of the hydrogen plant during one day



For the fuel cell usage for instance, the operation during one day shows the discontinuous way of supplying power from hydrogen fuel cell to the grid, since it is price responsive and has no constraint of firm capacity. This is also because the region of the case study, around Saint-Nazaire, is not a remote area, but is connected to the rest of the national system. The graph shows also that the hydrogen operator would have a discontinuous activity and suggests that he should diversify the usage of hydrogen by a multi-product energy supply. The intermittent use of the fuel cell puts in this case a pressure on the system and could reduce by half its technical lifetime (Menanteau et al., 2010).

Graph 6. Power supply from hydrogen fuel cell as a function of the market price

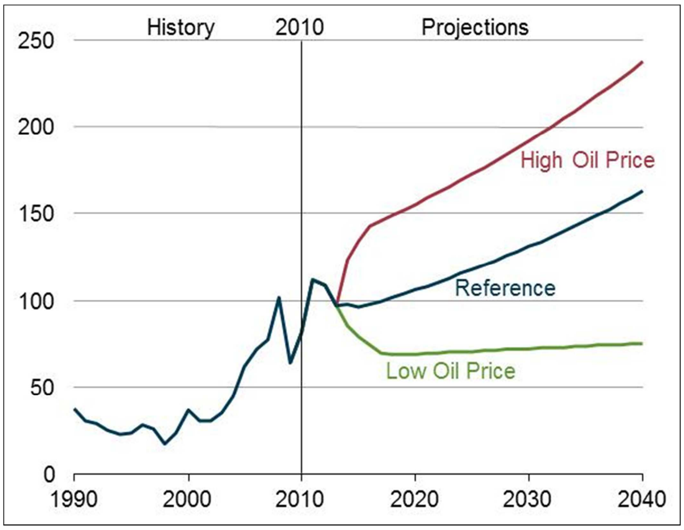


The intermittency of the wind power makes the hydrogen production intermittent as well. Hence, the flexibility of gas and power spot market segments gives the system the freedom to make the trade-off between favorable periods to produce and supply the hydrogen. Firm contracts with refueling stations instead constrain the periods of hydrogen production and storage, but ensure on the other hand the security of selling the hydrogen at a given price. This could give more visibility to investors to the energy market volumes and the expected profitability of the project. This allows also sizing the system components in connection with the expected market volume. Yet, in both cases, firm and flexible contracts, the uncertainty holds on the wind power profile; if the wind does not blow as expected, power withdrawal from the local grid would be necessary, which would lower the profits given the electricity cost incurred.

4.3. Sensitivity tests

The model is highly sensitive to the input values, especially the prices of hydrogen substitutes, such as power, gas and oil; and to investment costs assumed for each project component, as well. Alternative scenarios to oil price trends are found in different roadmaps used by the policy makers (EIA, 2013). The figure below illustrates three potential oil price evolutions in the future according to three scenarios, low, medium and high.

Graph 6. Oil price paths during 1990-2040 ($2011/barrel)



Source EIA (2013)

The study case assumes four scenarios of the oil price evolution, one documented by the EC (2013), and the three others by the EIA (2013), and assumes a zero probability for the low scenario to occur and an equal probability for the three others. For the gas and power prices, it is assumed an equal evolution as for the oil price. The values of the NPV indicators are reported in the table below together with the NPV expectation.

Table 6. The evolution of energy prices

	Oil Price 2013	Oil Price 2030	*Variation*	Proba Sce
SceLow	100	60	*-40%*	0%
SceMedium	100	130	*30%*	33%
SceHigh	100	180	*80%*	33%
SceBase	100	120	*20%*	33%

The results of sensitivity scenarios show that all cases record negative values of the expected NPV, as a combination of each scenario profitability and probability to occur in the future. One single case taken individually would record a positive NPV, the scenario Hydrogen-to-gas, for an increase of the fuel price of 80% from the current level.

Table 7. Results on the NPV expectation

Scenario		**NPV**			**Expected NPV, €/MWh**
		Base	**Medium**	**High**	
Mix usage	**H2-to-X**	-125	-124,9	-82	**-111**
	H2 only	-352	-306	-352	**-337**
Single application	**H2-to-Power**	-109	-109	-68	**-95**
	H2-to-Gas	-34	-34	**12**	**-19**
	H2-to-Fuel	-64	-64	-18	**-48**
Two applications	**H2-to-Gas, H2-to-Power**	-104	-104	-61	**-90**
	H2-to-Gas, H2-to-Fuel	-57	-57	-10	**-42**

4.4. Policy implications

The system impacts of the hybrid wind-hydrogen system are evaluated at four levels of the stakeholders involved in the project:

- **The wind power operator** has a lower profitability when it invests in hydrogen production as compared to the case where it operates alone, excepting the case where it would generate hydrogen for the natural gas network. Unless the regulation would oblige intermittent energies to balance their intermittency by means of storage, there would be no economic incentive to invest in such a capital intensive project in this study case. In France, the provision of firm capacity and ancillary services is not mandatory, neither for wind power plants nor for other generators. In the future, this arrangement could change with the current contraction of the current over-capacity and the increase in wind power penetration.

The regulation of intermittent renewable energy is ongoing and has as starting point the experience gained in islands, such as Corsica and Reunion Island. The Ministry of Environment launched in 2009 a call for tender for photovoltaic energy systems under the constraint for generators to control the intermittency of their power flows in the French islands (MEEDD, 2011). To that the endowment of PV generators with storage systems is mandatory in order to stabilize the frequency of the system. A similar context could be designed in the metropolitan France where constraints could be set on the generators to limit their power fluctuations.

Using other large-scale technologies than hydrogen storage medium, such as compressed air or pumped hydro storage, would limit the energy vectors to Power-to-Power applications and would exclude the applications to mobility and to gas. Therefore, other economic models for wind and storage would be necessary (Loisel et al., 2010, 2011).

- **The Transmission System Operator** beneficiates from the hybrid system operation, with more reliable output and the potential to have a continuous power if required. The integration of the wind power excess in form of H2-to-power makes increasing the use of the grid line and ensures a better use of the grid assets. The transmission line capacity factor increases from 54% to 67%.

- **The society overall** beneficiates from the support brought by the hydrogen plant to the wind energy integration and from the substitution between gas and oil with clean hydrogen. The wind power curtailment has been reduced significantly which would further substitute to other forms of energy in the French energy mix. On the road and sea transportation side, other benefits than carbon-emission free traffic would result, such as local pollution and noise removal. If the carbon market still does not fully internalize the carbon value in 2030, the clean hydrogen value will continue to remain highly underestimated on the energy market, despite its social benefits.

- **The industry** involved in all chains of the hydrogen production and storage needs a clear vision of the hydrogen market development potential. This implies from the regulation side the harmonization of standards of security among regions and countries for operating hydrogen plants, and the building of the infrastructure such as hydrogen pipelines and distribution stations for cars and ships. The components which have been optimized in this study to match the size of the wind power cluster (1 GW as a reminder) are not yet available on the market at this large scale; all the existing hybrid pilot plants have installed capacities of kWs orders of magnitude. Creating large-scale components would take years of R,D&D for the applications to become available and mature on the market. Therefore, signals should be created well in advance to ensure the emergence of hydrogen technologies.

Policy makers' involvement is crucial at this stage for the development of the hydrogen economy. This can take the form of supply-push and demand-pull policies. Supply push policies could stimulate innovation by supporting research and development activities. R&D funds, public-private partnerships, cost-sharing schemes and hydrogen infrastructure building are some of the supporting policies which would enhance the large-scale deployment of hydrogen. Demand pull policies can send market signals to investors that the potential for the hydrogen demand is high. It should be noted that in France, there is an exemption from energy taxes of the hydrogen use (Bleischwitz and Bader, 2010). By contrast, other countries, Germany, Austria, Netherlands, apply taxes on hydrogen when it is used as motor fuel. Ultimately, carbon taxation together with long-term environmental objectives would be the strongest signal which would guide the investors in low-carbon technologies, clean hydrogen included.

5. Concluding remarks

This research has investigated the project investment into a hybrid wind-hydrogen plant located in the French region Pays de la Loire. The hybrid scheme is based on cost-benefit sharing, where hydrogen is produced with zero cost wind power infeed. Several energy applications of the hydrogen are tested, such as power-to-power, power-to-gas and power-to-mobility. This paper has built realistic scenarios on the demand for hydrogen and the hydrogen production and storage cost projections for the year 2030. An optimization model has been built to optimize the design and the operation of the wind-hydrogen plant.

Main results show negative profits for all energy scenarios due to high investment costs in both wind energy and hydrogen production infrastructure which remains expensive related to the low energy prices of power, oil and gas. The production cost of hydrogen is of 4.2 €/kg H2 in the most economically interesting case (Hydrogen-to-gas) and is up to 47 €/kg H2 in the scenario of an isolated hydrogen plant.

The main conclusion for the design of the project is that combining too many usages needing each a different infrastructure could cumulate losses on the market. As for the contractual forms of the usages, the intermittency of the wind power and the hydrogen production makes the hybrid system to favor open supply to spot markets such as gas and power markets. For the fixed supply of fuel to refueling stations, other factors, regulatory and policy oriented, would trigger the investment in such expensive project. Oil prices should more than double to make the hydrogen production-storage-distribution an interesting economic option.

The wind power curtailment could be totally reduced; however, valuating the wind power excess would have a high investment cost related to the low market value. Yet, to the hydrogen market value one should add the social and system value that beneficiates to the various stakeholders. These benefits are the support to the wind power integration, increased reliability to the grid power, improved quality of the power supply, clean fuel for road and sea transportation and increased energy independency by reducing oil and gas consumption.

At a national scale, the main policy recommendations are towards helping consumers and industries selecting carbon-free technologies by means of carbon taxation and ambitious targets set for the long term. Regionally, policy support could make industrials and consumers familiar with the technology and the hydrogen use, and could further involve in the R&D activities. With the decentralization of the energy production, a strong commitment of regional policy makers is essential to the development of hydrogen infrastructure. This would give confidence on the investments possibilities and could guide the equipment manufacturers, energy operators and car and shipping stakeholders where hydrogen technology could find fertile ground.

Building the necessary infrastructure to produce, transport, store and deliver the hydrogen requires first of all licenses and operating permits; this is why the authorities should be involved at the earliest stage of the process. The relevant authorities is the region Pays de la Loire are working together with scientists, fishing industrials and shipping manufacturers in order to accelerate the development of the fishing vessel of the future, hydrogen fuel cell driven. [7] Regional concern to set basis for hydrogen along with marine energies in Pays de la Loire and the initiatives undertaken by the regional *Mission Hydrogène* show that the policy makers have already committed in creating prospects for hydrogen and a sustainable power system in the region.

References

Ademe, ATEE, DGCIS, 2013, Étude sur le potentiel du stockage d'énergie, http://www.enea-consulting.com/wp-content/uploads/peps-rapport-public-synth%C3%A8se.pdf

Aguado M, Ayerbe E, 2009, Economical assessment of a wind-hydrogen energy system using WindHyGen® software, International Journal of Hydrogen Energy 34: 2845-2854.

Bleischwitz R, Bader N, 2010, Policies for the transition towards a hydrogen economy: the EU case, Energy Policy 38: 5388-5398.

CEA, 2012, Les technologies de l'H2 au CEA, http://www.cea.fr/

EC, European Commission, 2013, EU Energy, Transport and GHG emissions trends to 2050, http://ec.europa.eu/energy/observatory/trends_2030/doc/trends_to_2050_update_2013.pdf

Gahleitner G, 2013, Hydrogen from renewable electricity: an international review of power-to-gas plants for stationary applications, Int. J. of Hydrogen Energy: 2039-2061.

EIA, U.S. Energy Information Administration, 2013, International Energy Outlook 2013, http://www.eia.gov/forecasts/ieo/liquid_fuels.cfm.

Jorgensen C, Ropenus S, 2008, Production price of hydrogen from grid connected electrolysis in a power market with high wind penetration, International Journal of hydrogen energy 33: 5335-5344.

Korps M, Greiner J, 2008, Opportunities for hydrogen production in connection with wind power in weak grids, Renewable Energy 33: 1199-1208.

Le Duigou A, Quéméré M M, Marion P, Decarre S, Sinegre L, et al. (2011). Développement des marchés de l'hydrogène : demande prospective dans l'industrie, production par énergie éolienne, stockage massif et distribution aux véhicules en région. *Revue de l'énergie* 62(600): 97-107.

Loisel, R., 2012. Power system flexibility with electricity storage technologies: a technical-economic assessment of a large-scale storage facility. Int. J. Electr.Power Energy Syst. 42 (1), 542–552.

Loisel R, Mercier A, Gatzen C, Elms N, Petric H., 2010, Valuation framework for large scale electricity storage in a case with wind curtailment. Energy Policy 2010;38/11:7323–37.

Loisel R, Mercier A, Gatzen C, Elms N., 2011, Market evaluation of hybrid wind-storage power systems in case of balancing responsibilities. Renew Sustain Energy Rev 2011;15:5003–12.

MEEDDM, Ministere de l'Ecologie, de l'Energie, du Developpement Durable et de la Mer, 2010, Analyse du potentiel national pour l'application de la cogénération à haut rendement.

http://www.developpement-durable.gouv.fr/IMG/pdf/101015_Rapport_potentiel_coge_pour_UE-1.pdf

[7] http://fr.dcnsgroup.com/wp-content/uploads/2014/07/La-bateau-de-pche-du-futur-va-natre-en-Pays-de-la-Loire.pdf

MEDD, Ministere de l'Ecologie, du Developpement Durable, des Transports et du Logement, 2009, updated in 2011, Appel d'offres pour la creation des centrales photovoltaiques en France, www.developpement-durable.gouv.fr/IMG/pdf/090706Cahier_des_chargesAppel_d_offresEnergieSolaire.pdf

Menanteau P, Quéméré M, Le Duigou A, Le Bastard S, 2010, Une analyse économique de la production d'hydrogène pour des usages transport à partir d'électricité éolienne, http://halshs.archives-ouvertes.fr/docs/00/53/75/63/PDF/PM_analyse-economique_RE_2010.pdf

NREAP, National Renewable Energy Action Plans. National action plan for the promotion of renewable energies 2009–2020; 2009. http://www.ec.europa.eu/energy/renewables/transparency_platform/doc/updated_nreap_france_en.pdf.

UNEP, United Nations Environment Programme, 2006, The hydrogen economy. A non-technical review, http://www.unep.org/publications/search/pub_details_s.asp?ID=3771.

Acknowledgements

We are very grateful to our colleague, Stefania Spinu for the work delivered on the database of the wind power potential, and to the Scientific Board of the Conference TEPP Nantes 2014 (Territories, Spaces and Public Policies), for having selected our work.

Annex 1. The methodology used for wind power data collection

Several constraints are taken into account when estimating the electricity output of the offshore power cluster. The power actually captured by the turbines is lower than the total energy available in the wind. This is a physical law known as the Betz limit which states that only a maximum of 59.26% of the kinetic energy can be extracted from the wind regardless of turbine design. Kinetic energy is converted into mechanical energy by the gearbox and then into electrical energy by the generator. The production function is hence given by:

$P = 0, 5\ C_t\ \rho\ A\ v^3$, where C_t is the average efficiency of each turbine, ρ is the average air density (1, 23 kg/m^3), A is the rotor swept area (17869 m^2) and v is the wind speed.
It is considered that no electricity is produced for wind speeds lower than 2, 77 m/s and the production function is applied for $v \in (2{,}77\text{-}11{,}22)$. Technical documentation provided by Alstom suggests that the *Haliade^{TM} 150-6MW* turbines reach full power at wind speeds of 13 m/s. However, due to incomplete data, a rated wind speed of 11, 22 m/s is calculated. It is considered that the machines are at their full rated power for wind speeds up to 25 m/s. The turbines are stopped for security reasons for wind speeds higher than 25 m/s. This study finds a net capacity factor of 35, 23% and a total production of 127, 72 ktep for an installed capacity of 480 MW.

Annex 2. The equations of the model

$$Objective\ Function:\ Max\ Profits = Revenues - Costs$$

$$Revenues = \sum_{hour=1}^{8760} \begin{matrix} price\_elec_{hour} \times \left(Wind_{Power_{hour}} + H2\_to\_power_{hour}\right) + \\ price\_reserve \times H2reserve_{hour} + \\ K\_price \times K\_reserved + \\ price\_gas \times H2\_to\_gas_{hour} + \\ price\_oil \times H2\_to\_mobility_{hour} \end{matrix}$$

$$Costs = \sum_{hour=1}^{8760} price\_elec_{hour} \times Withdrawal_{hour} + VOM$$

$$Wind\_Production_{hour} + Wind\_to\_H2_{hour} \leq Wind\_Profile_{hour}$$

$$Wind\_Production_{hour} + H2\_to\_power_{hour} + H2reserve_{hour} + \ Withdrawal_{hour} \leq grid\_line$$

$$H2\_Prod_{Total_{hour}} = \ H2\_from\_Withdrawal_{hour} + Negative\_reserve_{hour} + H2\_from\_Wind_{hour}$$

$$H2\_Prod_{Total_{hour}} \leq Capacity\_electrolyser$$

$$H2\_from\_Wind_{hour} = \ Wind\_to\_H2_{hour} \times efficiency_{electrolyser}$$

$$H2\_from\_Withdrawal_{hour} = Withdrawal_{hour} \times efficiency_{electrolyser}$$

$$H2_{Prod_{Total_{hour}}} = H2\_to\_gasnetwork_{hour} + H2\_to\_Cmpressor200_{hour} + H2\_to\_Compressor700_{hour}$$

$$H2\_compressed200_{hour} = H2\_to\_Cmpressor200_{hour} \times efficiency_{compressor200}$$

$$H2\_compressed700_{hour} = H2\_to\_Cmpressor700_{hour} \times efficiency_{compressor700}$$

$$StorageH2\_200bars_{hour} = StorageH2\_200bars_{hour-1} + H2\_compressed200_{hour} - (H2\_to\_power_{hour} + H2reserve_{hour}) \div efficiency_{fuelcell}$$

$$StorageH2\_700bars_{hour} = StorageH2\_700bars_{hour-1} + H2\_compressed700_{hour} - (H2\_to\_road_{hour} + H2\_to\_shipping_{hour}) \div efficiency_{destorage}$$

$$\sum_{hour=1}^{8760} H2\_compressed200_{hour} \geq \sum_{hour=1}^{8760} (H2\_to\_power_{hour} + H2reserve_{hour})$$

$$\sum_{hour=1}^{8760} H2\_compressed700_{hour} \geq \sum_{hour=1}^{8760} (H2\_to\_road_{hour} + H2\_to\_shipping_{hour})$$

$$\sum_{hour=1}^{8760} H2\_Prod_{Total_{hour}} \geq \sum_{hour=1}^{8760} (H2\_to\_gasnetwork_{hour} + H2\_to\_power_{hour} + H2reserve_{hour} + H2\_to\_road_{hour} + H2\_to\_shipping_{hour})$$

$$H2\_to\_gasnetwork_{hour} \leq Capacity_{pipeline}$$

$$H2\_to\_shipping_{hour} = ShipFuel\_Demand_{hour}$$

$$H2\_to\_road_{hour} = RoadFuel\_Demand_{hour}$$

$$\sum_{hour=1}^{8760} H2reserve_{hour} \leq 5\% \times positivereserve\_nationalDemand$$

$$\sum_{hour=1}^{8760} Negative\_reserve_{hour} \leq 5\% \times negativereserve\_nationalDemand$$